APPENDIX A

Northwest Power Supply Adequacy/Reliability Study – Phase 1 Report

DATA AND ASSUMPTIONS USED FOR THE RESOURCE DEVELOPMENT FORECAST

Project Financing

The financing assumptions for new generating resources are summarized in Table A.-1. Project developers are assumed to be unregulated private generating companies. New projects are assumed to be merchant plants, having long-term power sales agreements for little, if any of plant output when built. Project financing assumptions are based on the "Unregulated Independent" financing assumptions of the Fourth Power Plan[1]. Long-term general inflation rates are reduced from the 3.5 percent used in the Fourth Plan to 2.5 percent to reflect the generally lower inflation rates of the past several years and continuing strong federal anti-inflation policy. The nominal cost of debt and equity are reduced consistent with the reduction in general inflation rate. The debt/equity ratio of 80:20 used for the Fourth Plan is reduced to 70:30 to reflect the increased risk associated with merchant plant development. Finally, an after-tax cost of capital "corporate" discount rate is used in lieu of the 4.75 percent societal discount rate of the Fourth Power Plan. The corporate discount rate is intended to represent the discount rate used by plant developers in assessing project economics.

Table A-1: Base case financing assumptions for new power projects

Return on equity (%/yr)	17.3%
Interest on long-term debt (%/yr, real)	8.7 %
Debt/equity ratio	70/30
Amortization period (yr)	15
Federal income tax rate (%)	34%
State income tax rate (%)	3.7%
Property tax rate (on depreciated value) (%/yr)	1.4%
Insurance rate (on depreciated value) (%/yr)	0.25%
Debt financing fees (%)	2.0%
Discount rate basis	Weighted after-tax cost-of -capital
Discount rate (%/yr)	9.0%
General inflation (%/yr)	2.5%

[1] Northwest Power Planning Council. *Fourth Northwest Conservation and Electric Power Plan, Document 96-5 and 96-5A,* March 1996 and *Addendum to the Fourth Northwest conservation and Electric Power Plan Document 97-7*, April 1997.

Scheduled Resource Additions and Retirements

We assume that projects currently under construction are completed as scheduled, and that proposed retirements reported by WSCC[2] occur as scheduled. Our assumptions regarding scheduled additions are shown in Table A.-2; projects assumed to be retired are shown in Table A-3

Table A-2: Scheduled Resource Additions (7/1/99 & later)

Project	Fuel/Type	Capacity (MW)	Location	Service
Island Cogeneration 1	Natural gas/ Combined cycle combustion turbine w/cogeneration	250	Elk Falls, BC	Aug 2000
Stave Falls (New powerhouse)	Hydro	90	Stave R., BC	Dec 1999
Cobisa-Person	Natural gas/ Simple-cycle combustion turbine	140	Albuquerque, NM	July 2000
Fort Saskatchewan	Natural gas/ Combined cycle combustion turbine w/cogeneration	120	Fort Saskatchewan	Nov 1999
Joffre Cogeneration	Natural gas/ Combined cycle combustion turbine w/cogeneration	450	Joffre, AB	Jun 2000
Valmont	Natural gas/ Simple-cycle combustion turbine	37	Boulder, CO	Jun 2000
Arapahoe	Natural gas/ Simple-cycle combustion turbine	74	Denver, CO	Jun 2000
Rossdale 11 (Repower)	Natural gas/ Combined cycle combustion turbine	241	Edmonton, AB	Jan 2002
Suncor Cogeneration 1	Natural gas/ Combined cycle combustion turbine w/cogeneration	180	Ft McMurrey, AB	Jun 2000
Suncor Cogeneration 2	Natural gas/ Combined cycle combustion turbine w/cogeneration	180	Ft McMurrey, AB	Jun 2001
Klamath Cogeneration	Natural gas/ Combined cycle combustion turbine w/cogeneration	484	Klamath Falls, OR	Jun 2001
Sutter	Natural gas/ Combined cycle combustion turbine	500	Yuba City, CA	Jun 2001
Los Mendanos	Natural gas/ Combined cycle combustion turbine w/cogeneration	545	Pittburg, CA	Jun 2001
South Point	Natural gas/ Combined cycle combustion turbine	545	Bullhead City, AZ	Jun 2001

Table A-3: Scheduled Resource Retirements (7/1/99 & later)

Project	Fuel/Type	Capacity (MW)	Location	Retirement
Whitehorn 1	Fuel oil/ Simple-cycle combustion turbine	61	Point Whitehorn, WA	Nov 1999
Valley 3	Natural gas/Boiler-team	163	Sun Valley, CA	Jan 2000
Valley 4	Natural gas/Boiler-steam	160	Sun Valley, CA	Jan 2000
Vernon IC 1 - 5	Fuel oil/Reciprocating	21	Vernon, CA	Jan 2000
Battle River 1	Coal/Boiler-steam	31	Forestburg, AB	Oct 1999
Battle River 2	Coal/Boiler-steam	32	Forestburg, AB	Oct 1999
Rossdale 8	Natural gas/Boiler-steam	71	Edmonton, AB	Dec 1999

[2] Western Systems Coordinating Council. *Existing Generation and Significant Additions and Changes to Existing facilities 1997 - 2007*. January 1998.

Load Growth Forecast

Annual WSCC load growth is assumed to average 1.5 percent, the base case rate estimated for the Fourth Power Plan and used for the Council's earlier assessment of future Bonneville costs and revenues[3]. For this study, load growth rates are differentiated for individual load-resource areas, based on forecasts developed by Bonneville for its initial rate case proposal[4]. The load growth rates used for load-resource areas not appearing in the Bonneville work are those of the closest equivalent or adjacent areas of the Bonneville study. The annual load-growth forecasts used for the 15 load-resource areas are shown in Table A-5. The rates were held constant over the 20-year study period.

Table A-5: Load growth forecasts

Load-Resource Area	Annual Load Growth (%)
Western Washington and Oregon	1.52
Northern California	1.06
Southern California	1.06
British Columbia	1.36
Southern Idaho	1.52
Montana	1.52
Wyoming	1.74
Colorado	1.74
New Mexico	1.82
Arizona and southern Nevada	1.82
Utah	1.52
Northern Nevada	1.52
Alberta	1.36
Southwestern Public Service	1.82
Eastern Washington and Oregon and northern Idaho	1.52

Fuel Prices

The AURORA model requires price forecasts for natural gas, coal, nuclear fuel and other fuels used for production of electric power. Because of the importance of coal and natural gas for electric power generation, separate price series for individual load-resource areas are provided for these fuels.

Natural Gas

Natural gas prices are based on a price forecast for the Henry Hub, Louisiana trading hub. The Henry Hub price is adjusted by basis differential prices to yield prices for two regional supply basins, the Western Canada Sedimentary Basin (WCSB) (AECO trading hub) and the San Juan supply basin (Ignacio trading hub). Secondary basis differential prices are applied to the supply basin prices to yield "contract" natural gas prices for each load-resource area. This contract price represents the fuel price for a baseload plant such as a new combined-cycle unit. A portion of the contract price is treated as fixed. This is intended to simulate a gas supply contract with reserved transportation. Gas prices for peaking plants are obtained by adding a peaking differential. The resulting peaking gas price represents the generally higher fuel prices that peaking facility can be expected to pay because of spot market gas consumed during peak load periods. Peaking gas prices are treated as fully variable.

[3] (Cite for Bonneville costs and revenues study).
[4] Bonneville Power Administration. *2002 Initial Power Rate Proposal: Marginal Cost Analysis Study*. August 1999.

The long-term natural gas price annual escalation value used for this study is 0.8 percent, unchanged from that used for the 1998 assessment of Bonneville costs and revenues. However, base year gas prices have been increased at the recommendation of the study advisory group. The year 2000 price (used as the base year for long-term escalation for this study) is $2.40/MMBtu, compared to $2.05/MMBtu in the 1998 analysis.

In general, the supply basis and load-resource basis differentials used in this study are projections of the 10-year basis differential series developed for Bonneville's 2002 rate proposal. Because of the timeliness of the Bonneville analysis, we believe that the results of that work should supercede the differentials used in the 1998 Council study. Further discussion of these differentials is provided in Bonneville's marginal cost analysis report.

The Ignacio/Henry Hub basin basis differential is that proposed by Bonneville. This study, however, uses the AECO trading hub as the basis for northern load-resource areas rather than the Sumas interchange used in the Bonneville rate case. Our AECO/Henry Hub basis differential is Bonneville's "Sumas" differential, reduced by $0.05/MMBtu to reflect the transportation differential between the Sumas (Washington) interchange and the AECO (Alberta) hub. The AECO/Henry differential declines (i.e., the AECO price rises) from $ - 0.65/MMBtu in 1997 to $ - 0.30/MMBtu in 2009. This reflects the effect of pipeline expansions on Midwestern market access to Western Canada Sedimentary Basin gas. For many years, limited market access resulted in WCSB prices being significantly lower than Henry Hub prices, providing a price advantage for the Northwest. The negative differential between WCSB and Henry prices began to contract (i.e. WCSB gas prices began to rise) following the 1998 expansion of the Northern Border pipeline. The Alliance pipeline, expected to open in 2000, is expected to further strengthen the effect of the Midwestern market on WCSB prices. Increasingly evident declines in WCSB well productivity may further reduce the differential.

The choice of supply basin for specific load-resource area price series is based on the price correlation analysis described in Bonneville's 2002 Initial Power Rate Proposal. Some adjustments for revised and new load-resource areas have been made. The Nevada load-resource area, originally congruent with the state boundary and assigned to the San Juan producing basin by Bonneville, is now limited to northern Nevada. Because this area is served via the Paiute pipeline from southern Idaho, northern Nevada gas prices are based on AECO. Prices for the Southwestern Public Service load-resource area, new to this study, are based on the Ignacio hub, consistent with the adjacent New Mexico load-resource area.

The load-resource area basis differentials are also based on those developed by Bonneville. Differentials for areas based on AECO are generally increased by $0.05/MMBtu to account for the shift from Sumas to AECO. One exception is Alberta. Because the AECO hub is located within Alberta, the Alberta area differential remains at the Bonneville Canada area value of $0.20/MMBtu in 2000. The second exception is the new "Eastern Washington and Oregon, northern Idaho" area. This area receives the Bonneville Washington/Oregon differential of $0.25/MMBtu in 2000 because of its proximity to the AECO hub. The Northern Nevada differential of $0.45/MMBtu in 2000 reflects the indirect gas supply to this area via the Paiute lateral off the Williams pipeline in Southern Idaho. Differentials for southern California, New Mexico, Utah and Colorado are unchanged.

The resulting gas prices are shown in Table A-6. The table A-6 "contract" gas prices represent the full delivered cost of fuel for a baseload unit. In modeling unit dispatch, a portion of the contract gas price is treated as fixed. This portion, $ 0.175/MMBtu, is intended to represent roughly half of the transportation and other fixed costs of a typical gas supply contract. We assume about half of the gas supply for a baseload facility will be covered by contract.

Peaking gas prices are the full contract prices for each load-resource area, increased by $0.60/MMBtu. This represents the price that a peaking facility is expected to pay for spot market gas consumed during peak load periods. The peaking differential is that recommended by EPIS, the vendor of the AURORA model.

Other Fuels

Coal price forecasts are unchanged from the Council's 1998 assessment of future Bonneville costs and revenues. Because of stagnant demand and slow increases in productivity, base case coal prices are assumed to decline at 1 percent a year, real.

Fuel oil prices are those used for the Councils' 1998 study of Bonneville costs and revenues. Biomass fuel prices are those used in the 1998 study. These are from the Fourth Power Plan. The fuel price for facilities reported as fuelled by refinery gas are based on a 50:50 mix of zero-cost refinery waste gasses and purchased natural gas. Fuel prices for all nuclear plants except WNP-2 are from the Energy Information Administration Annual Energy Outlook. WNP-2 fuel prices have been lower than most because of the availability of fuel stocks from uncompleted projects. For WNP-2 fuel prices, we use the Energy Northwest long-term budget fuel price forecast 2009. Following 2009, we escalate WNP-2 fuel prices at the rate forecast by the Energy Information Administration.

Table A-6: Fuel prices ($/MMBtu)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
No. 1 Fuel Oil	5.00	5.03	5.05	5.08	5.10	5.13	5.15	5.18	5.20	5.23	5.26	5.28	5.31	5.33	5.36	5.39	5.42	5.44	5.47	5.50	5.52
No. 2 Fuel Oil	4.50	4.52	4.55	4.57	4.59	4.61	4.64	4.66	4.68	4.71	4.73	4.75	4.78	4.80	4.83	4.85	4.87	4.90	4.92	4.95	4.97
Henry Hub NG	2.53	2.04	2.38	2.40	2.42	2.44	2.46	2.48	2.50	2.52	2.54	2.56	2.58	2.60	2.62	2.64	2.66	2.68	2.70	2.73	2.75
WCSB (AECO) NG	2.13	1.69	2.28	2.30	2.32	2.34	2.37	2.39	2.41	2.43	2.46	2.47	2.50	2.52	2.54	2.56	2.58	2.60	2.62	2.65	2.67
San Juan (Ignacio) NG	2.33	1.84	2.18	2.20	2.22	2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	2.42	2.44	2.46	2.48	2.50	2.53	2.55
AB Contract NG	2.08	1.64	2.23	2.25	2.27	2.29	2.32	2.34	2.36	2.38	2.41	2.42	2.45	2.47	2.49	2.51	2.53	2.55	2.57	2.60	2.62
AZ & S. NV Contract NG	2.68	2.19	2.53	2.55	2.56	2.58	2.60	2.62	2.63	2.65	2.67	2.68	2.70	2.72	2.74	2.76	2.78	2.80	2.82	2.85	2.87
BC Contract NG	2.13	1.69	2.28	2.30	2.32	2.34	2.37	2.39	2.41	2.43	2.46	2.47	2.50	2.52	2.54	2.56	2.58	2.60	2.62	2.65	2.67
CO Contract NG	2.63	2.14	2.48	2.50	2.51	2.53	2.55	2.57	2.58	2.60	2.62	2.63	2.65	2.67	2.69	2.71	2.73	2.75	2.77	2.80	2.82
E. OR, WA & N. ID Contract NG	2.13	1.69	2.28	2.30	2.32	2.34	2.37	2.39	2.41	2.43	2.46	2.47	2.50	2.52	2.54	2.56	2.58	2.60	2.62	2.65	2.67
MT Contract NG	2.18	1.74	2.33	2.35	2.37	2.39	2.42	2.44	2.46	2.48	2.51	2.52	2.55	2.57	2.59	2.61	2.63	2.65	2.67	2.70	2.72
N. CA Contract NG	2.48	2.04	2.63	2.65	2.67	2.69	2.72	2.74	2.76	2.78	2.81	2.82	2.85	2.87	2.89	2.91	2.93	2.95	2.97	3.00	3.02
N. NV Contract NG	2.33	1.89	2.48	2.50	2.52	2.54	2.57	2.59	2.61	2.63	2.66	2.67	2.70	2.72	2.74	2.76	2.78	2.80	2.82	2.85	2.87
NM & SWPS Contract NG	2.63	2.14	2.48	2.50	2.51	2.53	2.55	2.57	2.58	2.60	2.62	2.63	2.65	2.67	2.69	2.71	2.73	2.75	2.77	2.80	2.82
S. CA Contract NG	2.73	2.24	2.58	2.60	2.61	2.63	2.65	2.67	2.68	2.70	2.72	2.73	2.75	2.77	2.79	2.81	2.83	2.85	2.87	2.90	2.92
S. ID Contract NG	2.18	1.74	2.33	2.35	2.37	2.39	2.42	2.44	2.46	2.48	2.51	2.52	2.55	2.57	2.59	2.61	2.63	2.65	2.67	2.70	2.72
UT Contract NG	2.63	2.14	2.48	2.50	2.51	2.53	2.55	2.57	2.58	2.60	2.62	2.63	2.65	2.67	2.69	2.71	2.73	2.75	2.77	2.80	2.82
W. OR & WA Contract NG	2.18	1.74	2.33	2.35	2.37	2.39	2.42	2.44	2.46	2.48	2.51	2.52	2.55	2.57	2.59	2.61	2.63	2.65	2.67	2.70	2.72
WY Contract NG	2.23	1.79	2.38	2.40	2.42	2.44	2.47	2.49	2.51	2.53	2.56	2.57	2.60	2.62	2.64	2.66	2.68	2.70	2.72	2.75	2.77
AB Peaking NG	2.68	2.24	2.83	2.85	2.87	2.89	2.92	2.94	2.96	2.98	3.01	3.02	3.05	3.07	3.09	3.11	3.13	3.15	3.17	3.20	3.22
AZ & S. NV Peaking NG	3.28	2.79	3.13	3.15	3.16	3.18	3.20	3.22	3.23	3.25	3.27	3.28	3.30	3.32	3.34	3.36	3.38	3.40	3.42	3.45	3.47
BC Peaking NG	2.73	2.29	2.88	2.90	2.92	2.94	2.97	2.99	3.01	3.03	3.06	3.07	3.10	3.12	3.14	3.16	3.18	3.20	3.22	3.25	3.27
CO Peaking NG	3.23	2.74	3.08	3.10	3.11	3.13	3.15	3.17	3.18	3.20	3.22	3.23	3.25	3.27	3.29	3.31	3.33	3.35	3.37	3.40	3.42
E. OR, WA & N. ID Peaking NG	2.73	2.29	2.88	2.90	2.92	2.94	2.97	2.99	3.01	3.03	3.06	3.07	3.10	3.12	3.14	3.16	3.18	3.20	3.22	3.25	3.27
MT Peaking NG	2.78	2.34	2.93	2.95	2.97	2.99	3.02	3.04	3.06	3.08	3.11	3.12	3.15	3.17	3.19	3.21	3.23	3.25	3.27	3.30	3.32
N. CA Peaking NG	3.08	2.64	3.23	3.25	3.27	3.29	3.32	3.34	3.36	3.38	3.41	3.42	3.45	3.47	3.49	3.51	3.53	3.55	3.57	3.60	3.62
N. NV Peaking NG	2.93	2.49	3.08	3.10	3.12	3.14	3.17	3.19	3.21	3.23	3.26	3.27	3.30	3.32	3.34	3.36	3.38	3.40	3.42	3.45	3.47
NM & SWPS Peaking NG	3.23	2.74	3.08	3.10	3.11	3.13	3.15	3.17	3.18	3.20	3.22	3.23	3.25	3.27	3.29	3.31	3.33	3.35	3.37	3.40	3.42
S. CA Peaking NG	3.33	2.84	3.18	3.20	3.21	3.23	3.25	3.27	3.28	3.30	3.32	3.33	3.35	3.37	3.39	3.41	3.43	3.45	3.47	3.50	3.52
S. ID Peaking NG	2.78	2.34	2.93	2.95	2.97	2.99	3.02	3.04	3.06	3.08	3.11	3.12	3.15	3.17	3.19	3.21	3.23	3.25	3.27	3.30	3.32
UT Peaking NG	3.23	2.74	3.08	3.10	3.11	3.13	3.15	3.17	3.18	3.20	3.22	3.23	3.25	3.27	3.29	3.31	3.33	3.35	3.37	3.40	3.42
W. OR & WA Peaking NG	2.78	2.34	2.93	2.95	2.97	2.99	3.02	3.04	3.06	3.08	3.11	3.12	3.15	3.17	3.19	3.21	3.23	3.25	3.27	3.30	3.32
WY Peaking NG	2.83	2.39	2.98	3.00	3.02	3.04	3.07	3.09	3.11	3.13	3.16	3.17	3.20	3.22	3.24	3.26	3.28	3.30	3.32	3.35	3.37
Nuclear Fuel - WNP-2	0.28	0.29	0.29	0.30	0.31	0.32	0.33	0.34	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.41	0.42	0.43	0.44	0.46	0.47
Nuclear Fuel - Other WSCC	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Refuse	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50	-3.50
Wood Waste	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
Biogas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refinery Gas	0.85	0.86	0.86	0.87	0.88	0.88	0.89	0.90	0.91	0.91	0.92	0.93	0.94	0.94	0.95	0.96	0.97	0.97	0.98	0.99	1.00
AB Coal	0.80	0.79	0.78	0.78	0.77	0.76	0.75	0.75	0.74	0.73	0.72	0.72	0.71	0.70	0.69	0.69	0.68	0.67	0.67	0.66	0.65
AZ & S. NV Coal	1.19	1.18	1.17	1.15	1.14	1.13	1.12	1.11	1.10	1.09	1.08	1.07	1.05	1.04	1.03	1.02	1.01	1.00	0.99	0.98	0.97
BC Coal	0.80	0.79	0.78	0.78	0.77	0.76	0.75	0.75	0.74	0.73	0.72	0.72	0.71	0.70	0.69	0.69	0.68	0.67	0.67	0.66	0.65
CO Coal	0.83	0.82	0.81	0.81	0.80	0.79	0.78	0.77	0.77	0.76	0.75	0.74	0.74	0.73	0.72	0.71	0.71	0.70	0.69	0.69	0.68
ID Coal	1.20	1.19	1.18	1.16	1.15	1.14	1.13	1.12	1.11	1.10	1.09	1.07	1.06	1.05	1.04	1.03	1.02	1.01	1.00	0.99	0.98
MT Coal	0.80	0.79	0.78	0.78	0.77	0.76	0.75	0.75	0.74	0.73	0.72	0.72	0.71	0.70	0.69	0.69	0.68	0.67	0.67	0.66	0.65

N. CA Coal	1.45	1.44	1.42	1.41	1.39	1.38	1.37	1.35	1.34	1.32	1.31	1.30	1.29	1.27	1.26	1.25	1.23	1.22	1.21	1.20	1.19
N. NV Coal	1.21	1.20	1.19	1.17	1.16	1.15	1.14	1.13	1.12	1.11	1.09	1.08	1.07	1.06	1.05	1.04	1.03	1.02	1.01	1.00	0.99
NM & SWPS Coal	1.00	0.99	0.98	0.97	0.96	0.95	0.94	0.93	0.92	0.91	0.90	0.90	0.89	0.88	0.87	0.86	0.85	0.84	0.83	0.83	0.82
OR, WA & N. ID Coal	1.14	1.13	1.12	1.11	1.10	1.08	1.07	1.06	1.05	1.04	1.03	1.02	1.01	1.00	0.99	0.98	0.97	0.96	0.95	0.94	0.93
S. CA Coal	1.45	1.44	1.43	1.41	1.40	1.39	1.38	1.37	1.36	1.35	1.34	1.32	1.31	1.30	1.29	1.28	1.27	1.26	1.25	1.24	1.23
UT Coal	0.85	0.84	0.83	0.82	0.82	0.81	0.80	0.79	0.78	0.78	0.77	0.76	0.75	0.75	0.74	0.73	0.72	0.72	0.71	0.70	0.70
WY Coal	0.76	0.75	0.74	0.74	0.73	0.72	0.72	0.71	0.70	0.69	0.69	0.68	0.67	0.67	0.66	0.65	0.65	0.64	0.63	0.63	0.62

New Resource Alternatives

To model the future electricity supply system, AURORA adds new increments of generating capacity when the net present value cost of adding a new resource is less than the net present market value of the output of the resource. A selection of new resources is provided from which the AURORA selects capacity additions. The generating resource options considered for this study are the following:

- Natural gas-fired combined-cycle combustion turbine power plants
- Natural gas-fired simple-cycle combustion turbine power plants
- Pressurized fluidized bed combustion coal-fired combined cycle plants
- Central-station solar photovoltaic power plants
- Central-station wind-turbine arrays

Significant market penetration of distributed generation technologies such as packaged fuel cell or microturbine cogeneration units could begin before the end of the decade. Because of modeling limitations, distributed generating technologies could not explicitly be considered for this study. Because the period of interest is early to mid-decade, we do not believe that distributed generation potential would significantly affect the conclusions of this study.

The cost and performance assumptions for the new generating resource options considered in this study are summarized in Table A-7.

Table A-7: Base case cost and performance assumptions for new generating resource options

(1997 base year except as noted)

	Natural Gas (Combined-cycle	Natural Gas (Simple-cycle)	Coal	Solar	Wind
Technology	250 MW class industrial-grade combined-cycle power plant	160 MW class industrial-grade simple-cycle power plant	340 MW pressurized fluidized bed combustion power plant	100 MW fixed flat-plate photovoltaic plant	50 MW wind turbine generator arrays
Fuel	Natural gas with partial firm transportation and backup fuel oil supply	Spot market natural gas and backup fuel oil supply	Coal	Solar	Wind
Availability (thermal units) Capacity factor (renewables)	92 %	87 %	80 %	21 % (CA, WA, OR, ID) 22 % WY 23 % (CO, NM) 25 % (AZ, UT, NV)	35 % (high plains) 24 % (basin & range) 30 % (Pacific coast)
Heat Rate (Btu/kWh) [a]	7167	10630	8425	--	--
Heat rate improvement (20-yr ave., %/yr)	-0.5%	-0.8 %	-0.5 %	--	--
Capital cost [b], including grid interconnection ($/kW)	$583	$333	$1395	$3400	$ 960 (high plains) $1380 (Basin & range) $1125 (Pacific coast)
Capital cost escalation (20-yr ave., real, %/yr)	-0.5%	-0.8 %	-0.5 %	-8.0 %	-2.8 %
Fixed operating cost [c] ($/kW/yr)	$18	$12	$39	$8	$25 (high plains) $47 (basin & range) $32 (Pacific coast)
Variable operating cost (mills/kWh)	0.8	0.1	1.0	0.8	3.1 (high plains) 3.5 (basin & range) 3.5 (Pacific coast)
Operating cost escalation (20-yr ave., real, %/yr)	-1.5%	-1.8 %	-1.5 %	0.0 %	-3.8 % (fixed) -1.1 % (variable)
Development & construction lead time (months)	24/24	24/12	36/36	24/12	24/12
Development & construction annual cash flow (%/yr)	1/1/59/39	1.5/1.5/97	1/1/3/25/45/25	1/1/98	1/1/98
Service life (years)	30	30	30	30	30

[a] Equipment seeing service in 1997.

[b] "Overnight" capital cost (excludes financing costs, escalation and interest incurred during construction).

[c] Exclusive of property taxes and insurance. See financial assumptions, Table A-1.

Combined-cycle Combustion Turbine Power Plants

The gas combustion turbine-combined cycle power plant using natural gas fuel is the technology of choice for new base load capacity throughout North America for economic and environmental reasons. Relatively low and stable gas prices and low-cost, efficient, reliable and environmentally clean gas turbine-combined cycle technology have lead to easily sited and quickly constructed power plants. At current gas prices, these plants are capable of producing power at lifecycle costs of about 2.5 cents per kilowatt hour. Unlike pure steam-cycle plants, gas turbines have not approached practical efficiency limits. Continuing demand for more efficient and lower cost gas turbines for both transportation and stationary applications is expected to encourage continued improvement of this technology. This should maintain the competitive position of gas turbine-combined cycle power plants, even in the face of moderate increases in natural gas prices.

Our combined-cycle combustion turbine power plant study assumptions are based on 250-megawatt class industrial units[5]. This class of combustion turbine is the predominant machine currently employed for power plants intended for baseload duty. No cogeneration load or credit is assumed, though cogeneration units are not uncommon in practice.

Capital Cost

The capital cost of new combined-cycle plants is based on the reported cost of the Clark Public Utilities River Road power plant in Vancouver, Washington. River Road, a 248-megawatt General Electric 107FA combined-cycle power plant, entered service in late 1997. The River Road construction cost was adjusted as described below to arrive at a representative plant cost for each of the load and resource geographic areas considered in the Aurora model.

Combined-cycle power plant development cost estimates for a group of prospective Northwest sites was prepared for the Fourth Power Plan[6]. These estimates were intended to capture the effects of site-specific conditions, and possible economies of scale at sites capable of accommodating multiple units. Because one of these sites was Vancouver, the subsequent availability of the River Road cost information allowed the Fourth Plan estimates to be calibrated using actual cost experience.

The calibrated site development cost estimates were increased by 2.7 percent to represent the estimated average degradation of capacity over the life of the plant, yielding "lifetime average" capital costs. The result, $546/kW (1997 dollars) is assumed to be representative of the cost of developing new combined cycle plants in the Northwest under market conditions prevailing during the mid-1990's.

Gas turbine vendors and the power plant construction industry were encountering slack market conditions when the River Road plant was constructed. For this reason, the estimate was increased by 10 percent to $601/kW to represent base case (equilibrium market) conditions thought more typical of the 20 year study period.

Further adjustments for regional price differentials and elevation effects were made to arrive at combined-cycle capital cost estimates for specific load and resource areas. The regional price indices shown in the second column of Table A-8 are assumed to decline linearly from the 1997 values of Table 2 to a uniform 100 by 2015. Because the output of a gas turbine is sensitive to ambient air density, capital costs were

[5] 250 MW has been the nominal capacity of plants having "1x1" (one gas turbine, one steam turbine) configuration using gas turbines such as General Electric 7FA machines. Other configurations may have greater output. In addition, recent performance improvements have lead to 1x1 ratings considerably in excess of 250 megawatts.

[6] The development of this factor is further described in Appendix F of the *Fourth Northwest Conservation and Electric Power Plan*. The factor used here is the difference between the estimated cost of developing a single unit combined-cycle power plant at a Vancouver, WA site (the location of the actual River Road plant) and the average estimated cost of developing units at the "Group 1" set of sites identified in the Fourth Plan. The Group 1 sites are those sites for which construction permits were currently held or being sought at the time the Fourth Plan was in preparation. Group 1 sites could accommodate from one to four 250 MM class units.

further adjusted for the effect of elevation on atmospheric density, as shown in the third column of Table A-8.

The resulting capital costs were used for the Council's 1998 assessment of Bonneville cost and revenues. Since that study, powerplant development activity has significantly increased. Turbine delivery lead times from order are reported to be three years. An equilibrium or even a seller's market now exists. While reported power plant development costs have increased in response to the more active market, it does not appear that costs have increased to the levels expected under equilibrium market conditions in the 1998 study. For this reason, the 1998 base case overnight capital cost assumption has been reduced 3 percent, to $583 dollars per kilowatt capacity (1997 dollars) for purposes of this study.

Table A-8: Load and Resource Area Cost Adjustments

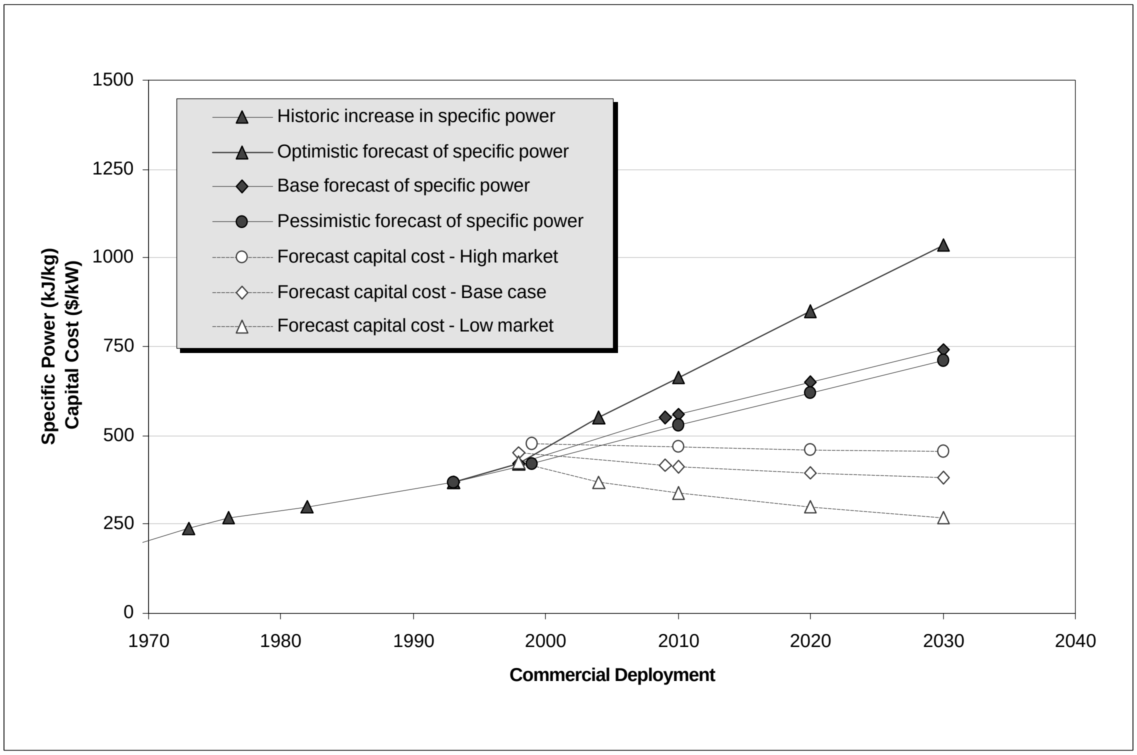
Load & Resource Area	Regional price Indices (1997, declines to zero by 2015)	Elevation–related Cost Indices (Gas and wind turbine technologies)
Western Oregon & Washington	100	102
Northern California	105	102
Southern California	105	102
British Columbia	105	110
Southern Idaho	100	110
Montana	100	119
Wyoming	102	119
Colorado	102	119
New Mexico	102	119
Arizona and southern Nevada	102	110
Utah	100	119
Northern Nevada	105	110
Alberta	105	119
Southwestern Public Services	102	119
Eastern Washington and Oregon and northern Idaho	100	102

Commercially available gas turbine power plants have not approached practical limits of cost or thermodynamic efficiency. The cost of future plants is expected to decline over time as design, materials and manufacturing processes improve. Other factors equal, increases in specific power increase the power available from a machine of given physical size. This leads to per-unit-output capital cost reductions. Forecast future improvements in the specific power of gas turbine combined-cycle plants were used to estimate future cost reductions resulting from technology improvements[7].

Because the advanced materials and manufacturing processes needed to increase specific power may be more expensive than conventional materials and processes it is unlikely that future cost reduction will be in direct proportion to improvements in specific power. Optimistic, expected and pessimistic forecasts of the rate of future improvement in the specific power rating of gas turbines prepared for this study are shown in Figure A-1. Fifty, 30 and 10 percent of the forecast increases in specific power were assumed to translate into capital cost reductions for the low, base and high cases,

Figure A-1: Historical and forecast specific power and capital costs for combined-cycle gas turbine power plants respectively.

[7] Specific power is the power output of a turbine per unit mass of working fluid passing through the machine (e.g. kW/lb).



Operation and maintenance cost

The 1997 base year fixed and variable operating and maintenance (O&M) costs are based on 1995 estimates prepared for the Fourth Power Plan. The Fourth Power Plan fixed O&M costs were adjusted to the 1997 base year of this study using three factors. These include 1995 - 97 general inflation, the combined-cycle capital cost reduction forecast described above, and a operation and maintenance cost reduction factor of 2.5 percent annually, developed by the Energy Information Administration[8] to account for observed reductions in O&M attributable to increased competitive pressure. The resulting fixed O&M costs were further adjusted by the regional price and elevation indices of Table A-8 to yield specific fixed O&M costs for each load and resource area. Variable O&M costs were similarly derived from Fourth Power Plan estimates except that elevation adjustments were not taken.

The fixed operating and maintenance costs of future plants are assumed to decline in proportion to the capital cost technology improvement indices of Figure A-1 and the EIA competitive pressure cost reduction factor (the latter through 2004). Variable O&M costs are assumed to continue to decline through 2004 by the competitive pressure cost reduction factor.

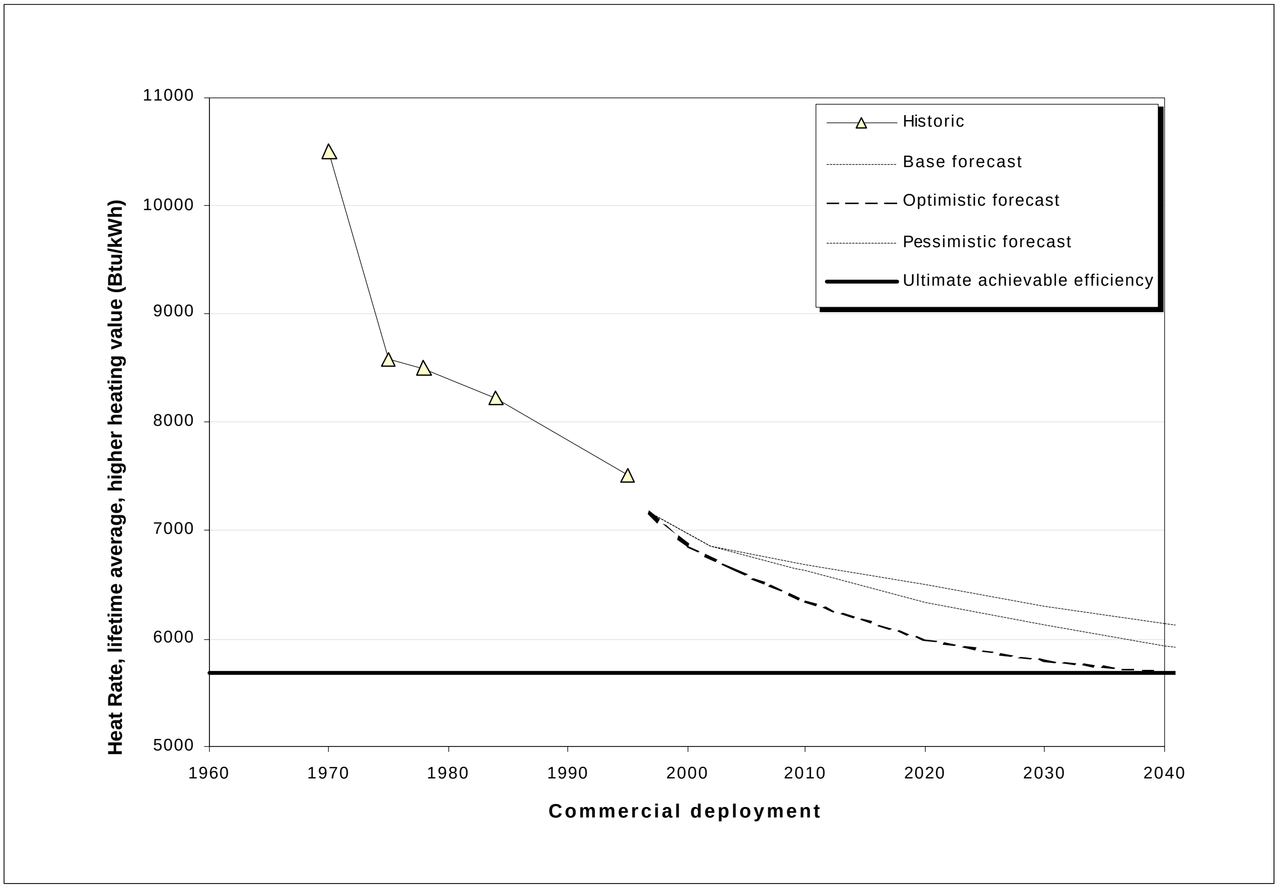
Heat Rate

Combined-cycle plant heat rates are based on the measured “new and clean” performance of the River Road plant. This value was derated to account for expected average performance degradation over the life of a plant. This yielded a lifetime average heat rate typical of 1995-vintage equipment.

[8] Energy Information Administration *1998 Annual Energy Outlook*.

Commercially available gas turbine combined-cycle plants have not approached feasible thermodynamic efficiency limits, and continued improvement in heat rate is expected[9]. Optimistic, expected and pessimistic forecasts of heat rate improvements were developed, based on historic efficiency improvements and theoretically achievable efficiency (Figure A-2).

Figure A-2: Historical and forecast specific heat for combined-cycle gas turbine power plants



Simple-cycle Combustion Turbine Power Plants

Simple-cycle combustion turbine power plant assumptions are based on 160-megawatt class industrial units (e.g., General Electric Frame 7 machines). These plants are expected to operate primarily as peaking units. The majority of simple-cycle units currently being developed in North America are of this class.

Capital Cost

The capital costs of new simple-cycle gas turbines are based on equipment-only gas turbine generator set budgetary package prices appearing in the *Gas Turbine World 1998-99 Handbook*[10]. *Handbook* prices are developed through discussions with architect/engineering firms, project developers and original equipment

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[9] Chiesa, Paolo, et. al. 1993. "Predicting the ultimate performance of advanced power cycles based on very high temperature gas turbine engines". Presented at the International Gas Turbine and Aeroengine Congress and Exposition, Cincinnati, OH, May 24 - 27, 1993.

[10] Gas Turbine World 1998-99 Handbook. Pequot Publications, Fairfield, Connetticut.

manufacturers. These package prices are FOB factory and include a gas turbine, electric generator, starting system, skid, enclosure, inlet filter, silencer and controls. Not included are substations, switchyards, gas supply facilities, backup fuel storage facilities, administrative buildings, special emission controls, foundations and civil works. Also not included are engineering, construction management and owner's costs.

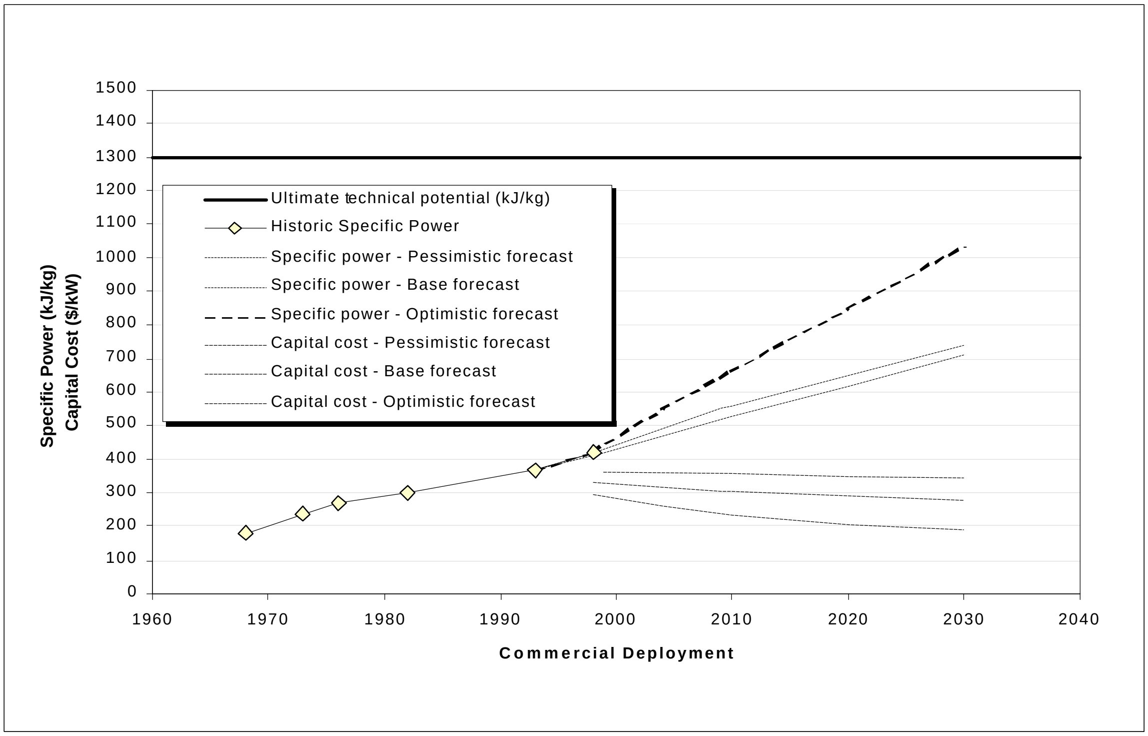
Per kilowatt turnkey project costs were estimated by averaging the equipment costs of the General Electric 7FA and the Siemans V84-3A. gas turbine generators. The ABB GT24, another machine of this type, was not included because only one of these machines was in service in the US at the time and price information may be distorted by the price incentives frequently offered by equipment manufacturers to place first-of-a-kind machines. For the base market case these prices were increased by a 10 percent market equilibrium adjustment to account for the slack market conditions of the past several years.

Gas Turbine World estimates that balance-of-plant costs range from 60 to 100 percent of gas turbine generator set costs. We assumed that on average balance-of-plant costs would be 80 percent of equipment costs. Simple-cycle units are assumed to be constructed in pairs to obtain additional operating flexibility and economies of scale. Based in earlier Bonneville studies, the cost of a second unit is estimated to be 75 percent of a first unit. The resulting cost of a two-unit plant, derated by 2.6 percent to account for inlet, exhaust and auxiliary equipment losses and further derated to account for average lifecycle output degradation, is $333/kW.

Simple-cycle combustion turbine costs for the specific load and resource areas were obtained by adjusting the general capital cost values by regional price and elevation indices of Table A-8.

The cost of future plants is assumed to decline over time with improvements to design, materials and manufacturing. Forecast future improvements in combustion turbine specific power was used as a proxy for technology improvement, as described for combined-cycle units. Ultimate, historical and forecast improvements in simple-cycle combustion turbine specific power are shown in Figure A-3 along with our forecast reduction in capital cost.

Figure A-3: Historical and forecast specific heat and capital costs for simple-cycle gas turbine-generators



O&M cost

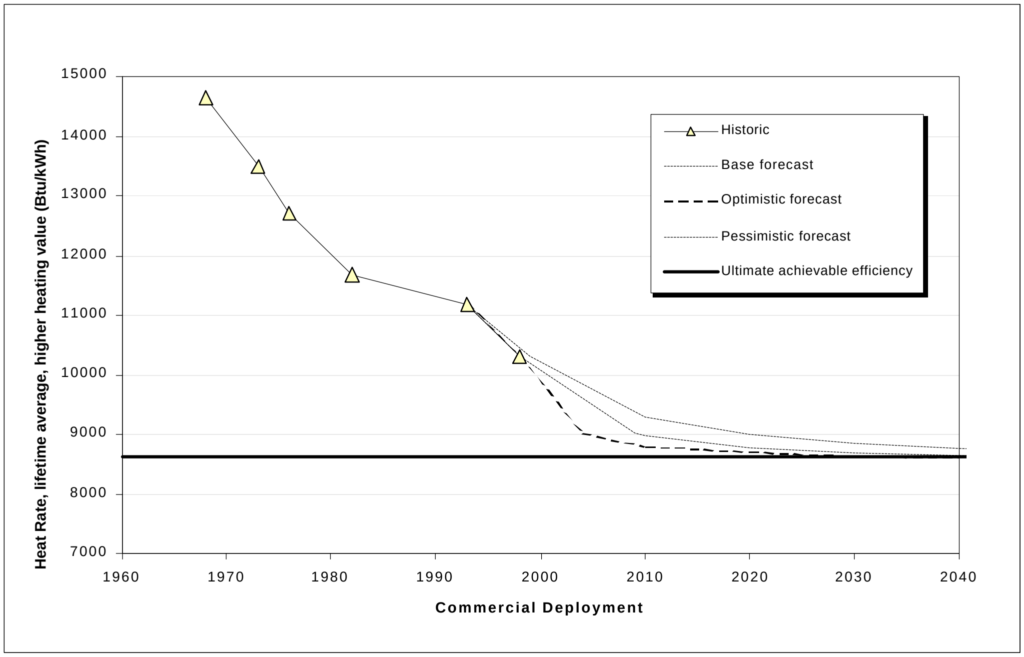
Operating and maintenance cost estimates are based on estimates for 80 megawatt-class simple-cycle units prepared for the Fourth Power Plan. The fixed operating and maintenance cost for 160 megawatt units was estimated by scaling the per kilowatt 80 megawatt-class estimates by the ratio of the capital costs. Variable operating costs were assumed to be the same for both classes of plants. The resulting estimates were further adjusted as described for combined-cycle units.

Heat Rate

Simple-cycle combustion turbine heat rates are based on nominal lower heat rate values reported in the *Gas Turbine World 1998-99 Handbook* for the General Electric 7FA and the Siemans V84-3A. gas turbine generators. The higher heat rate nominal average was increased by 1.11 to yield an higher heating value heat rate. This value was derated for inlet, exhaust and auxiliary losses to yield a net heat rate of 10411 Btu/kWh. This “new and clean” value was further derated by 2.1 percent to yield a lifetime average value of 10630 Btu/kWh.

Plants delivered at future dates are assumed to benefit from improved technology. Three heat rate improvement forecasts are based on pessimistic, expected and optimistic forecasts of combustion turbine thermal efficiency improvements. Historical and forecast heat rates are shown in Figure A-4.

Figure A-4: Historical and forecast specific heat and capital costs for simple-cycle gas turbine-generators



Coal-fired Power Plants

Coal is the energy source for approximately 23 percent of the generating capacity of the WSCC region. Coal resources are abundant and widespread within the WSCC. Major deposits are located in Alberta, Montana, Wyoming, Utah, Colorado, Arizona and New Mexico. Most of these deposits occur as thick, shallow seams, and can be produced at low cost using surface mining methods. Coal could supply the electric needs of the WSCC region for several hundred years or more. The principal uncertainties facing future development of coal-fired power plants is the cost of competing natural-gas fired combined-cycle power generation and the effects of possible efforts to control production of carbon dioxide, a greenhouse gas.

Coal-fired electric power generating technologies considered for resource additions in this study included pulverized coal-fired steam-electric plants and pressurized fluidized bed combustion power plants.

The pulverized coal-fired steam-electric plant is a mature power generating technology in use throughout the west. It is a pure steam cycle and has attained its maximum practical efficiency at subcritical steam pressures. Supercritical steam pressures would require costly materials to ensure reliable operation. At this time it appears to be more economical to develop alternatives employing the inherently more efficient gas-turbine combined cycle than to attempt to improve the efficiency of pure steam-electric technology.

A promising alternative to steam-electric coal technology is the pressurized fluidized bed combustion (PFBC) combined-cycle power plant. In this technology, coal is combusted in a pressurized furnace. The pressurized gaseous products of combustion are cleaned and used to power a gas turbine-generator. Steam, produced both in the pressurized boiler and from the hot exhaust of the gas turbine powers a steam turbine-generator. PFBC technology offers the advantages of higher thermodynamic efficiency, more compact size, more opportunity for factory fabrication and lower cost compliance with air emission criteria. PFBC technology is being demonstrated at several plants and is expected to be commercially available in the early 2000s. The representative PFBC technology used for the study is a single 340 megawatt unit, available for commercial service in 2005.

Earlier resource addition studies using AURORA suggested that new coal resources would not be selected in the early years of the study, if at all. As modeled for this study PFBC plants, once commercially available, are economically superior to conventional coal-fired steam power plants. Conventional coal-fired power plants were thereafter omitted the set of new resource options used for this study.

Capital Cost

The capital cost for PFBC coal technology are based on 1995 estimates prepared for the Fourth Power Plan. The Fourth Power Plan estimate was adjusted to the 1997 base year of this study using the 1995 - 97 general inflation and the combined-cycle capital cost reduction forecast described earlier. The resulting cost was further adjusted by the regional price and elevation indices of Table A-8 to yield specific costs for each load and resource area. (because PFBC plants utilize gas-turbine combined-cycle technology, we assume that the technological improvement indices developed for natural gas-fired combined-cycle plants would also apply to PFBC plants). The resulting base year capital cost is $1395/kW.

The technology improvement cost indices developed for gas-turbine combined-cycle plants were used to derive the cost of future PFBC plants.

Operating costs

Operating and maintenance cost assumptions for coal technologies were derived from those developed for the Fourth Power Plan as described for natural gas-fired power plants.

Heat rate

Heat rate assumptions for PFBC coal technologies were derived from those developed for the Fourth Power Plan as described for natural gas-fired power plants

Solar Power Plants

Very high quality solar resources are found in Nevada, Utah and Arizona. Good quality resources are found in the adjacent states. Electrical loads in the southern portion of the WSCC region are strongly affected by irrigation and air conditioning. This results in strong daily and seasonal coincidence of solar resource and electrical loads. Continued decline in the cost of photovoltaic module costs may eventually lead to the development of plants for bulk power production.

While we are not aware of a comprehensive estimate of solar development potential for area within WSCC, we assumed that several thousand megawatts of capacity could be sited within any of the load-resource areas. However, to expedite model operation, we assumed that large-scale central-station photovoltaic development is not likely in the Western Washington and Oregon, British Columbia, Montana or Alberta load-resource areas within the twenty-year period of this assessment. In general, these areas exhibit poor load-solar resource coincidence.

The solar power plant assumptions used for this study are based on the estimates for 100 megawatt central-station photovoltaic plant prepared for the Fourth Power Plan. Photovoltaics were chosen as the representative solar technology because the technology is commercially available, current costs are known and cost trends are evident. Other solar technologies that might achieve significant market penetration during the study period include rooftop and other distributed photovoltaic applications and solar thermal technologies such as power towers and Stirling dish power plants.

These assumptions were considered preliminary. The intent was to refine these estimates if significant amounts of central-station photovoltaic capacity was selected for development during any of the model runs. Because significant development of photovoltaic resources did not occur in these studies, these initial estimates were not modified.

Capital Cost

Capital costs were based on estimates prepared for the Fourth Power Plan, and include the estimated cost of typical interconnection to the main grid. The Fourth Power Plan estimate was adjusted to the 1997 base year of this study using the 1995 - 97 general inflation and the photovoltaic technology capital cost reduction forecast developed for the Fourth Plan. The resulting cost was further adjusted by the regional price indices of Table A-8. The resulting base year cost is $3400/kW.

Photovoltaic system costs are expected to continue to decline as the technology improves and as manufacturing capacity expands. The cost of future year development was calculated by extending the Fourth Plan photovoltaic cost escalator through the study period.

Operating and Maintenance Costs

Operating and maintenance costs were based on estimates prepared for the Fourth Power Plan. Costs were adjusted to 1997 dollars, but otherwise held constant in real terms over the study period.

Energy Production

Annual average capacity factors were based on performance estimates appearing in the Fourth Power Plan for a photovoltaic plant sited at Whitehorse Ranch in southeastern Oregon, a good solar resource area. The average annual capacity factor of this plant was estimated to be 21%. Annual average capacity factors for other areas were assumed to be in proportion to the best average annual solar irradiation of the area in question. The monthly shape factors for Whitehorse Ranch were used for all other areas.

Wind Power Plants

The wind resource of each load-resource area was characterized as one of three general types identified in previous Council assessments of Pacific Northwest wind resources. “High Plains” resources are typical of the high-elevation Great Plains east of the Rocky Mountains. These areas possess abundant very high-quality wind resources, but are generally distant from major load centers. Examples include Medicine Bow area of Wyoming and the Blackfoot area of north-central Montana. “Pacific Coast” resources are scattered, but of high quality and relatively close to load centers. Examples include Altamont in the Bay Area, the Columbia River Gorge and Cape Flattery of Washington’s Olympic Peninsula. “Basin & Range” wind resources occur on ridges running perpendicular to prevailing winds. These can be of fairly high quality, but are of limited extent and generally distant from load centers. Examples include Albion Butte in southern Idaho and Pueblo Ridge on the Oregon/Nevada border.

Each of the 12 Aurora areas were characterized by the wind resource type appearing to be most representative of the area (Table A-9).

Table A-9: Load and resource area wind resource assumptions

Aurora Load & Resource Area	Wind Resource Type	Annual Capacity Factor	Monthly Shape Factor
Western Oregon & Washington	Pacific Coast	30 %	Cape Flattery, WA
Northern California	Pacific Coast	30 %	Flat
Southern California	Pacific Coast	30 %	Flat
British Columbia	High Plains	35 %	Horse Heaven, WA
Southern Idaho	Basin & Range	24 %	Albion Butte, ID
Montana	High Plains	35 %	Blackfoot, MT
Wyoming	High Plains	35 %	Blackfoot, MT
Colorado	High Plains	35 %	Flat

New Mexico	High Plains	35 %	Flat
Arizona and southern Nevada	Basin & Range	24 %	Flat
Utah	Basin & Range	24 %	Albion Butte, ID
Northern Nevada	Basin & Range	24 %	Pueblo, OR
Alberta	High Plains	35 %	Blackfoot, MT
Southwest Public Services	High Plains	35 %	Flat
Eastern Washington and Oregon and northern Idaho	Pacific Coast	30 %	Horse Heaven, WA

Capital Cost

Base year overnight capital costs of wind power plants are based on estimates prepared for the Fourth Power Plan. In the Fourth Power Plan, wind power development costs were estimated for 48 promising wind resource areas in the Northwest for which good resource and geographic data is available. The Fourth Plan estimates include permitting, engineering, equipment, erection, overhead costs for wind farm development and interconnection to the main grid. Though these estimates are several years old, they remain consistent with current wind farm development costs. A representative development cost for each of the three types of wind resources ("Pacific coast", "basin and range" and "high plains") was obtained by averaging the development cost estimates for several Northwest resource areas of the respective type. The resulting estimates were adjusted to the 1997 base year considering general inflation and a wind technology cost reduction forecast prepared for the Fourth Power Plan. The resulting costs were further adjusted by the regional price and elevation indices of Table A-8 to yield wind resource capital costs for each load and resource area.

O&M cost

The base year fixed and variable O&M costs are based on estimates prepared for the Fourth Power Plan. Operating and maintenance costs for the three types of wind resources were derived using the approach described for capital costs. The resulting costs were adjusted to the 1997 base year using historical general inflation, the Fourth Power Plan wind technology cost reduction forecast and EIA O&M cost reduction factor described earlier. The resulting fixed O&M costs were further adjusted by the regional price and elevation indices of Table A-8 to yield specific fixed O&M costs for each load and resource area. Variable O&M costs were adjusted by the regional price indices only.

Capacity Factor

Representative capacity factors were calculated for each of the three types of wind resources by averaging the estimated capacity factors for the Pacific Northwest sites chosen to characterize each type of resource. The Fourth Power plan capacity factor estimates are based on annual average wind speeds and performance curves of representative 1995 wind turbine technology. Correction is made for elevation, and in-farm and grid interconnection losses. The resulting annual average capacity factors are 30 percent for Pacific coast resources, 24 percent for basin and range resources and 35 percent for high plains resources. Monthly shape factors were applied to areas where records from representative wind resource areas were available (Table A-9). Constant annual output was assumed for other areas.

Future improvement in wind turbine yields is captured in the capital and operating cost technology improvement indices described above.